- BEFORE THE PUBLIC SERVICE COMMISSION OF UTAH -

In the Matter of the Application of PACIFICORP for Approval of an IRP-based Avoided Cost Methodology for QF Projects Larger than One Megawatt	))))))	DOCKET NO. 03-035-14 ORDER

ISSUED: April 19, 2006

By The Commission:

INTRODUCTION AND PROCEDURAL BACKGROUND

On October 31, 2005, the Utah Public Service Commission ("Commission") issued its Report and Order approving methods for calculating avoided generation costs for cogeneration Qualifying Facilities (QF) greater than one megawatt and small power production QFs greater than three megawatts. Avoided costs are costs PacifiCorp ("Company") would incur to serve its native load "but for" the generation provided by the QF. The Order directed parties to convene a workgroup and provide a case-by-case method to calculate avoided transmission costs and losses within 21 days of the Order.

Pursuant to the October 2005 Order and as a result of the workgroup, on November 21, 2005, the Utah Division of Public Utilities ("Division") filed the QF Transmission Task Force Report. The report states the parties were unable to agree upon a method to determine avoided transmission capacity costs and losses. The report consists of a summary matrix of the task force participants' positions, appended by the individual statements of some participants. The Company's statement included its proposed methods.

On November 30, 2005, four parties filed requests for clarification, reconsideration or rehearing of various decisions in the October 2005 Order. Wasatch Wind

LLC ("Wasatch Wind") filed its Request for Clarification and Petition for Reconsideration of Order; the Committee Consumer Services ("Committee") filed its Request for Reconsideration; UAE Intervention Group ("UAE") filed its Petition for Review, Rehearing and Clarification; and, the Company filed its Petition for Rehearing or Reconsideration.

On December 12, 2005, Wasatch Wind filed its Response to Petitions for Rehearing and Clarification. On December 14, 2005, the Company filed its Response to UAE Intervention Group's Petition for Review, Rehearing and Clarification and Wasatch Wind's Request for Clarification and Petition for Reconsideration of Order. On December 15, 2005, Pioneer Ridge LLC filed its Response to the Committee's Request for Reconsideration and PacifiCorp's Petition for Rehearing or Reconsideration. On December 16, 2005, Mountain West Consulting, LLC ("Mountain West") filed its Response to the Committee's Request for Reconsideration and PacifiCorp's Petition for Rehearing or Reconsideration.

On February 2, 2006, the Commission issued its Order on Reconsideration and Clarification stating it required additional testimony and hearing on the following three issues: determining the appropriate method for calculating avoided transmission capacity costs, determining the appropriate method for determining the avoided cost of transmission line losses, and to reconsider Company requirements for providing access to its GRID computer model. GRID is the Company's hourly production cost computer simulation model and is used to calculate QF indicative energy prices. A scheduling order was issued January 10, 2006, setting the dates for filing testimony and hearing these three issues. Other issues for which parties requested clarification, reconsideration or rehearing were addressed in the Commission's February 2, 2006, Order on Reconsideration and Clarification.

Pursuant to the scheduling order, on February 10, 2006, testimony was filed by the Company, the Division, Mountain West and Wasatch Wind on the three issues requiring additional testimony and rehearing. On February 17, 2006, rebuttal testimony was filed by the Company, the Division, Mountain West, Wasatch Wind and the Committee. On February 24, 2006, pursuant to notice, a hearing was held, oral testimony provided by these parties, and the Commission questioned the witnesses on various aspects of the proposed methods.

POSITIONS OF THE PARTIES

Parties provide testimony on methods for calculating the costs of transmission capacity and transmission losses avoided by the Company when it purchases power from a QF. Parties also provide recommendations regarding Company requirements for providing access to GRID. We review the parties' positions on each of these three issues.

Avoided Transmission Capacity Cost Method: Avoided transmission costs are the transmission capital investments QFs may help the Company avoid or defer making as a result of the QF's location on the Company's transmission system.

The Company proposes to calculate avoided transmission capacity costs using a case-by-case method identifying QF project-specific net benefits to planned Company transmission facilities. The method is proposed for each QF project requesting to be interconnected to the system as a firm Network Resource, as described in the Company's Open Access Transmission Tariff (OATT), at the transmission level.

To calculate the net benefit in transmission facility costs, the Company proposes to use the Federal Energy Regulatory Commission interconnection study procedure and the interconnection process contained in the OATT. This process requires both an interconnection study and an integration study be conducted for every interconnection request received by the Company.

The interconnection study defines requirements to reliably interconnect the generator to the Company's system and provides the party requesting interconnection the site-specific interconnection costs. The integration study, known as the Transmission System Impact Study (SIS), defines the impacts of the resource on the operation of the transmission system and any requirements necessary to meet load or to move energy from point of receipt to point of delivery. For example, the SIS assesses requirements necessary to reserve transmission capacity on the Company's system for delivery of QF energy to load. The Company proposes to expand the SIS slightly to include a second study, also referred to by parties as the avoided cost portion of the SIS, wherein it would include the five-year outlook of future investments and the reliability requirements to install the QF and look at the difference between the current study and the five-year requirement to define any avoided or deferred investments.

To identify transmission cost impact, the SIS uses the base case power flow model developed and provided by the Western Electricity Coordinating Council (WECC). The model is developed jointly by all utilities in the WECC and is used by these same utilities for planning and system impact studies. For the purpose of calculating QF avoided transmission cost, the Company may be required to add some changes to the model to include any lower voltage systems not already included in the overall WECC models. The Company describes lower voltage transmission as 46 kilovolt (kV), 69 kV, 115 kV, and 138 kV lines.

The Company proposes to limit the avoided cost portion of the SIS to the 138 kV system and below. It argues avoided cost analysis of the higher voltage system will require additional study expense, primarily labor, and time because it may require joint planning studies with other utilities. Further, it argues, QFs are likely to be too small to have any effect on high voltage system facility costs. The Company proposes to limit the avoided cost study period to five years and to include only transmission additions that are currently in its five-year plan. The Company states its detailed transmission planning horizon does not extend to ten years and the use of a ten year horizon would introduce unnecessary uncertainty. The expected annual carrying charge associated with the transmission additions affected by the QFs forms the basis for an annual credit or assessment to a QF over the five year period. Although the Company initially believed it could complete the necessary studies for avoided transmission cost analysis in the same 90 days required for the large generators in its OATT, its proposal for large QFs is to extend this time frame from 90 to 120 days. For small QF generators, the time to complete studies would be doubled, from 30 to 60 days.

The Division's preferred method for determining avoided transmission capacity costs is that each QF be examined for individual impacts, both positive and negative, to the transmission system. Currently, the Division testifies, the cost piece of this study is undertaken by PacifiCorp Transmission upon request by the QF for interconnection and PacifiCorp Transmission could also assess benefits during this study. The Division states the study expansion may result in a longer study period and higher study costs, so the QF developer should be allowed to opt out of the benefit study portion if it does not believe its facility could provide any significant benefits to the transmission system. This method should apply only to firm resources because non-firm resources cannot be depended upon for reliability purposes and do not avoid either generating or transmission capacity. However, the Division supports use of this method for both thermal and wind resources. The Division supports limiting the study period to five years because it believes this time period will not exclude transmission necessary to implement IRP resources because of the longer lead time of transmission projects relative to generating facilities. The Division believes a QF should have the option of expanding the study to include not only 138 kV lines, as in the Company's proposal, but also high voltage line implications, if any. The Division recommends the QF developer bear any additional costs and time delays that accompany such an expanded study.

Wasatch Wind generally supports the Company's method but disagrees with the Company's proposal to exclude the transmission resources identified in its Integrated Resource Plan and to limit the analysis to five years. Wasatch Wind argues these constraints cause the model to understate avoided transmission capital costs and transmission expenditures. In Wasatch Wind's view, to deny the IRP ten-year period makes application of the Company's proposal inconsistent with the purposes of this docket, which is to develop IRP-based avoided costs.

Wasatch Wind recommends a wind QF receive avoided transmission capital costs when the Company makes capital improvements to the transmission system to accommodate the Proxy wind resource which is the last competitively negotiated wind contract. Wasatch Wind reasons that in such a case, the Company would negotiate with the wind project owner to recover those costs, resulting in a lower Proxy wind contract price. These Company costs should be included in the QF's indicative price to ensure ratepayer neutrality. The wind QF should then receive an avoided transmission capital cost prorated to the size of its project. Although Wasatch Wind does not foresee this happening often, it recommends the Commission allow for this possibility in order to avoid gaming by the Company or the developer of the competitively bid wind project.

Mountain West appears to generally support the Company's method but argues wind QFs are also entitled to the credit, recommends a process for accomplishing this, and argues it is inappropriate to exclude consideration of the benefits that occur when the QF interconnects above 138 kV or to exclude planned transmission resources in the IRP ten-year period.

On rebuttal, the Committee supports the Company's method with two exceptions. First, avoided transmission payments should be considered for transmission impacts above 138 kV unless the Company can offer definitive proof that impacts above 138 kV will never occur. Second, the Committee supports the Division's recommendation to allow QFs to opt out of the transmission benefits portion of the system impact study in order to save the QF time and money in the application process.

Avoided Cost Method for Transmission Losses: The Company proposes an adjustment for transmission line losses be made to the Partial Displacement Differential Revenue Requirements QF energy payments based on a case-by-case comparison of the location of the QF to the location of the proxy plant. The adjustment increases energy payments when the QF is closer than the proxy plant to Wasatch Front loads and decreases energy payments when the QF is farther than the proxy plant to Wasatch Front loads. It does not define the points from which "closer" or "farther" will be measured.

When the QF is interconnected at the high voltage transmission level, the delivered energy is either increased or decreased by the Company-specific system-wide average high-voltage transmission loss factor designated in its FERC approved Open Access Transmission Tariff (OATT). In the rare case the QF is interconnected at distribution level transmission, the delivered power is increased or decreased by the Company-specific system-wide average distribution level loss factor designated in its OATT. The Company proposes to apply this adjustment only when the QF delivered energy is firm and not intermittent. The Company defines wind resources as intermittent.

The Company proposes an option to the method described above. The QF developer should also be allowed to request and pay for an individual line loss study. The results of this study would form the basis for an energy payment adjustment as described above.

The Division's proposed method for calculating avoided losses is explained by an example which is basically consistent with the Company proposal, but indicates avoided losses be calculated as the difference in losses incurred by the proxy plant versus the QF. This appears to be slightly different than the Company proposal to credit average system losses to all QF output when the QF is closer than the proxy plant to Wasatch Front loads. Specifically, the Division's method implies the avoided losses are a function of the difference in distance from load. However, there is no detail regarding the loss factors to apply nor the points from which to measure the difference in distance. The Division argues the method should apply only to QF deliveries dispatched at the request of the Company. The Division argues QF energy deliveries that are either non-firm or "must-take" i.e., the consequence of a unilateral decision of the QF developer, are ineligible for an avoided cost line loss adjustment. This is because such line losses cannot be tied to a particular plant, the underpinning presumption in this method, and therefore it is very difficult to ensure ratepayer neutrality. The Division is uncertain if the method should apply to wind QFs because the wind proxy is a market contract. The Division excludes wind QFs from the adjustment based on its intermittent characteristics which the Division defines as non-firm.

The Committee supports the Company's and Division's methods, including application only to firm, and not intermittent, QF deliveries.

Wasatch Wind and Mountain West support the Company's method, but argue the method should also apply to wind and non-firm QF energy deliveries because losses physically occur when transferring energy regardless of whether the energy is contractually firm, non-firm or intermittent.

Company requirements for providing access to its GRID computer model:

The Company proposes to provide GRID access through the internet by the end of July, 2006 subject to vendor delivery schedules.

In the interim, the Company will provide stand-alone GRID computers upon request. Four computers will be readily available and the Company can buy, assemble and deliver additional GRID computers in about 30 days. The Company will provide training on an as needed basis so that the training coincides with the need to be able to run the model. The Company will provide a contact name and phone number for hardware and software support that will be generally available during normal business hours. In addition, in rebuttal testimony, the Company presented its plans to port GRID to the internet so that parties could provide comments to improve the implementation process, as requested by the Committee. In hearing, no party opposed the Company's final proposal to provide GRID access and training.

DISCUSSION, FINDINGS AND CONCLUSIONS

All parties generally agree with the Company's method for calculating avoided transmission facility costs. We find this case-by-case approach reasonable and approve its use for indicative pricing subject to our decisions below resolving the areas of disagreement. There is disagreement, as described in the parties positions above, regarding the voltage level of facilities included in the analysis, the length of the study period, and applicability to wind QFs.

Lacking record evidence to the contrary, we find excluding higher voltage analysis by definition is incorrect and may understate avoided cost. Further, we note the already expanded time line proposed for avoided cost study completion and consider this an adequate buffer for the additional work. Therefore, we direct the Company to include transmission facilities over 138 kV in the avoided cost portion of the SIS.

Because the higher voltage study process may cause delay in results that may be out of the control of the Company, any delays must be communicated to the QF applicant when known. For example, if there is a need for joint planning studies with other utilities, the Company must notify the QF applicant of the delay and permit the QF applicant to opt out of the extended portion of the study to avoid the time delay. We note this opt-out provision differs in part from the Division’s and Committee’s opt-out recommendation. It appears the Division and Committee recommend the QF be allowed to opt out to also avoid the additional expense of the avoided cost portion of the SIS. Cost recovery of performing the avoided cost portion of the SIS from the requesting QF is inconsistent with our view of the appropriate cost recovery mechanism. As with any other avoided cost study, this study cost is to be recovered through the general rate case revenue requirement calculation and recovered in rates.

We agree with the Company that uncertainty increases with an expanded analytical time horizon. However, we conclude it is inconsistent to evaluate avoided generation costs assuming IRP resources but then exclude IRP resources to evaluate avoided transmission costs. We direct the Company to expand the avoided cost study period to ten years and include in the study, the planned transmission projects in the most recent IRP or IRP Update Report that are consistent with the Company’s least cost-least risk portfolio.

Parties are inconsistent in their positions regarding the applicability of the method to wind QFs. The Company and Division support application of the method to wind QFs. Although the Company believes a wind QF cannot be dispatched when needed and therefore cannot reliably serve load at all times, the Company argues each QF case for transmission cost avoidance or deferral needs to be assessed on its own merits. Wasatch Wind and Mountain West are concerned the method may not apply to a wind QF because it is paid a price based on a wind proxy contract that may already compensate for avoided transmission costs. However, the Company's method is not based on the transmission costs associated with any proxy resource per se. Rather, the method takes into account the expected operating characteristics of any QF generator, including wind, interconnecting as a Network Resource, and studies the reliability impacts of the interconnecting generator and determines avoided transmission capacity costs over the study horizon. As such, the concern raised by Wasatch Wind and Mountain West is unwarranted. We agree with the Company and Division and find the Company's method shall apply to QFs regardless of fuel type. We also agree with the Company and Division that QFs requesting non-firm or must-take agreements cannot avoid facility additions required to meet firm load requirements and conclude they are ineligible for the avoided transmission capital cost payments.

With respect to the Company and Division's proposed methods to identify the cost of avoided line losses, we conclude the record is insufficient to determine that either method is generally reasonable and meets the ratepayer indifference standard. Both lack sufficient detail and rationale to justify implementation at this time. There is scant testimony explaining how the

Company or Division methods maintain ratepayer neutrality. Therefore, we do not approve any method for calculating the avoided costs associated with transmission losses in this docket. We identify the following concerns with the proposed methods.

First, the Company's FERC OATT loss factors are inconsistent with the loss factors approved to set retail rates and therefore use of these loss factors may be inconsistent with ensuring ratepayer neutrality. Testimony references FERC OATT loss factors that were calculated in a 1991 study using a method unapproved by this Commission. In litigated general rate cases since the 1991 study, this Commission has used factors from the previous Commission-approved study to set retail rates.

As requested by Mountain West and unopposed by any party present at the hearing, we take administrative note of the more recent 2001 transmission line loss study that was completed using the Commission-approved method. We note the high-voltage transmission line energy loss factor is nearly unchanged since the 1991 study despite the addition of the Cholla, Craig, Hayden, Hermiston and Gadsby power plants.[1] This fact underscores Company testimony in this case stating one project is not going to make a big difference in system line losses. It also calls into question the propriety of the plant-by-plant methods proposed in this case.

The 2001 transmission study reveals line losses are a function of transmission line distance, voltage level and transformation between voltage levels. However, the Company's method does not account for the difference in distance between the QF and its proxy plant and

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[1] The 1991 transmission energy loss factor is 1.0448 and the 2001 transmission energy loss factor is 1.04543.

the Division's method provides too little detail regarding the implementation of a distance sensitive method.

With respect to voltage-level differences in losses, we are concerned the Company's proposal misstates the level of losses avoided. For example, it appears reasonable to apply a high-voltage level loss factor to a QF interconnecting at a distribution-voltage line when it is compared to a proxy resource interconnecting at a high-voltage line; however, the Company's method credits this QF with a distribution level loss-factor. It appears ratepayers could be paying for distribution line losses twice in this instance: once to the QF and then again in transmitting the QF energy to distribution-level loads. Only when the QF is supplying energy to an onsite load does a payment for avoiding distribution line losses, as in the Company-proposed adjustment, appear reasonable. When questioned in hearing regarding the possibility of the Company's method resulting in a double payment for losses by ratepayers, no party provided a plausible explanation or answer to the concern.

We are also concerned the Company's method does not appropriately value line losses. The cost of line losses to ratepayers for the proxy plant and the QF is different. The Company's method values the cost of avoided losses at the marginal cost of energy, i.e., the QF's energy price, even though the cost of losses for all other generating plants to ratepayers is based on average system generation cost. We have no record evidence that paying QFs marginal rather than average energy cost for losses is reasonable, fair and meets the ratepayer indifference standard.

We also find “load center” is imprecisely defined in the Company’s and Division’s methods. This lack of specificity could prove to be controversial. Additionally, we find no analytical support for selecting Utah load rather than system load as the correct point of comparison for determining the avoided cost to ratepayers of a change in transmission losses caused by a QF’s location relative to the proxy plant. Indeed, parties use system load as the point of reference for comparing a wind QF to its proxy and Utah load for the point of reference for comparing a thermal QF with its proxy with little discussion this inconsistency is reasonable or based on a clearly articulated principle.

Finally, we approve the Company’s proposal to provide GRID access and training in the interim prior to its being made available on the Internet.

ORDER

NOW, THEREFORE, IT IS HEREBY ORDERED, that:

1. We approve the Company’s method, as modified herein, to determine avoided transmission capacity costs for indicative prices provided pursuant to Schedule No. 38, for QFs integrating as a firm Network Resource, regardless of fuel type. The modifications are: the avoided cost portion of the system impact study shall be expanded to ten years, include transmission facilities above 138 kilovolts and include the Company’s most recent IRP or IRP update transmission projects that are consistent with the least cost-least risk portfolio.

2. The Company is ordered to notify the QF when any delay in the avoided cost portion of the system impact study is required that is beyond the control of the Company, and permit the QF to opt out of the extended portion of the avoided cost portion of the study to avoid the time delay.

3. Recovery of costs to perform QF avoided cost portions of the system impact studies are to be determined through a general rate case proceeding through their inclusion in the revenue requirement calculation and recovery in rates.

4. We direct the Company to provide GRID access and training as proposed by the Company and described in this Order.

DATED at Salt Lake City, Utah, this 19th day of April 2006.

/s/ Ric Campbell, Chairman

/s/ Ted. Boyer, Commissioner

/s/ Ron Allen, Commissioner

Attest:

/s/ Julie Orchard
Commission Secretary
G#48620